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(54) Title: GEOMECHANICAL WEAKENING WITH SURFACE ACTING AGENTS

(57) Abstract: A method of hydraulic fracturing of a reservoir to improve drainage.



GEOMECHANICAL WEAKENING WITH SURFACE ACTING AGENTS

BACKGROUND OF THE INVENTION

[0001] Hydraulic fracturing or “fracking” is the propagation of fractures in a rock layer by a pressurized fluid. The oil and gas industry uses hydraulic fracturing to enhance subsurface fracture systems to allow oil or natural gas to drain more freely from the reservoir to production wells that bring the oil or gas to the surface. However, there many uses for hydraulic fracturing outside of the petroleum industry, including to stimulate groundwater wells, to precondition rock for cave in mining, to enhance waste remediation processes, to dispose of waste by injection into deep rock formations, including CO₂ sequestration, to measure the stress in the earth, and for heat extraction in geothermal systems.

[0002] In hydraulic fracking, an injection fluid, usually including water or brine and a polymer, is injected into a reservoir at pressures high enough to fracture the rock. The two main purposes of fracturing fluid or “frack fluid” in oil reservoirs is to extend fractures in the reservoir and to carry proppants, such as grains of sand, into the formation, the purpose of which is to hold the fractures open after pressure is removed without damaging the formation or production of the well. The polymer thickens the frack fluid, allowing it to more effectively carry the proppant deeper into the reservoir.

[0003] Without fracking, the time needed to drain a field would be inordinately long—in a tight field it could be in the order of hundreds of years. The only way to drain the oil in a reasonable time is to drill more wells—e.g., up to 40 wells per square mile in a tight field—a very expensive undertaking, or to fracture the field. The existence of long fractures allows the fields to be drained in a reasonable time period, with fewer wells, and in a cost effective way.

[0004] Since hydraulic fracturing was introduced in 1949, close to 2.5 million fracture treatments have been performed worldwide. Some believe that approximately 60% of all wells drilled today are fractured. Fracture stimulation not only increases the production rate, but it is credited with adding to reserves—9 billion barrels of oil and more than 700 Tscf of gas added since 1949 to US reserves alone—which otherwise would have been uneconomical to develop. In addition, through accelerating production, net present value of reserves has increased.

[0005] In 1976, high-rate “hesitation” fracturing was used to cause what he called “dendritic” fractures—with tree like branching patterns. The method was invented from the observation of unusually good production increases from a number of wells that had been

temporarily shut in due to equipment failures. Since the two groups of wells differed primarily in a single factor—an inadvertent shut-down period—another group of wells was selected for controlled tests of this factor, and it was found that when an intentional shut-down period of one hour was put in the frack plan, the first month's production was about double.

[0006] The US3933205 Kiel patent describes the method, now known as the “Keil process” or “dendritic fracturing.” The process uses cyclic injections to form extraordinarily long, branching flow channels. Fracking pressures induce spalling (flaking of rock fragments) from the fracture faces. When the well is shut in and then reinjected, the fluid movement moves the debris to the ends of the fractures, causing increased pressures at the end, and thus further propagating the fracture in a direction perpendicular to the initial fracture. Repeated cycles cause further branching. The transverse fractures will eventually intersect and communicate with natural fractures that parallel the direction of the primary fracture, thus a fully branched drainage system is developed. Further improvement can be had if the wells are opened for reverse flow during the shut-down period.

[0007] The Kiel method has been applied with good results to a wide range of formations at depths to 11,500 ft. Most of more than 400 dendritic (branching) fracturing jobs performed since the 70's have shown sustained productivity increases of 2-5 times those generated by conventional fracturing.

[0008] Although fracking is quite successful, even incremental improvements in technology can mean the difference between cost effective production, and reserves that are uneconomical to produce. One area of improvement would be the possibility of reducing the high pressures needed to propagate a fracture in a reservoir, and/or to provide longer, deeper fractures at a given pressure.

[0009] In the mining industry, some research has suggested that the use of surfactants can cause geomechanical weakening of rock, allowing the production of deeper fractures when drilling. The work utilized fused silica samples (quartz) fractured under controlled conditions with various surfactants. The theory proposed that surfactants reduced the free surface energy of porous tight gas rock that was being fractured. It was believed that with the right surfactant or combination of surfactants, the energy required to induce and propagate a fracture could be reduced. Further the fracture area could be increased by enhancing the bifurcation of the induced

fracture. However, this work applies to a rock-bit interface, and although intriguing, there is no reasonable expectation that the effects can be duplicated in a hydrocarbon reservoir.

[0010] US20110259588 explores the use of an acid for **reducing** geomechanical weakening using potassium acetate. The inventor contemplates the use of conventional additives, such as viscosifier, crosslinker, scale inhibitor, biocide, foamers, defoamers, anti-foamers, emulsifiers, de-emulsifiers, and surfactants in the frack fluid, but there was no recognition or attempt to use surfactants alone for geomechanical weakening, and indeed the application teaches that the opposite is desirable. In fact, the primary purpose of surfactants used in stimulating sandstone reservoirs is to reduce to reduce emulsion tendencies between reservoir oil and treatment fluids.

[0011] Thus, there is no recognition in the art that surfactants could be use to deepen fractures in oil and gas reservoirs by geomechanical weakening.

SUMMARY OF THE INVENTION

[0012] The disclosure generally relates to the use of charge modifiers, such as surfactants in a fracturing fluid for geomechanical weakening a reservoir rock, and thus the propagation of deeper or longer fractures at a given pressure.

[0013] The method utilizes the surface chemistry alteration capabilities of surface acting agents to alter the tensile strength of the rock matrix. This alteration in tensile strength affects the fracture creation and propagation properties. The end result is an increase in fracture area, which increases conductivity and, therefore, production. The concentration, type and application of the surface active agent is dictated by the geomechanics of the specific reservoir. The application of the surface acting agents may vary from direct injection and fracture, to pump and soak methods of various design, as well as pretreatment and other methods to maximize the desired effect.

[0014] The process outlined in this disclosure is applicable to any porous media that is being hydraulically fractured with fluid.

[0015] The composition of the fluid is varied depending on the chemistry, porosity, lithology, physical conditions and environment of the rock being stimulated. The injection rate and pumping conditions are also varied depending on the reservoir encountered.

[0016] One example of a typical optimization/pumping process might be to: (1) Obtain rock from the formation that is to be stimulated. This rock should be recovered in a saturation and stress condition that is as close as possible to reservoir conditions. Outcrop or core that has not been preserved can also be utilized, but this would not be optimal.

[0017] (2) Subject cores to hydraulic fracturing conditions with fluids composed of various surfactant or surfactant blends while measuring the fracture propagation pressures, fracture toughness and, if possible, fracture bifurcation indexes. Possible surfactants that could be utilized include but are not limited to various cationic fluorocarbon surfactants, nonylphenols, non-ionic and anionic surfactants and other materials capable of altering the free surface energy of the subject rock. Some examples of surfactants that could be utilized are shown in Table 1. An optimized system would be composed of the surfactant or surfactant blend, which provided the lowest energy to propagate the fracture, while maximizing the fracture bifurcation index. This fluid will be called a Chemomechanically Weakening Fluid (CMWF) in future references. The literature indicates that the concentration required to do this is in the neighborhood of the CMC (Critical Micelle Concentration) of the surfactant being utilized.

[0018] (3) Mix the CMWF into the base fluid being used to induce hydraulic fractures into the subject reservoir rock.

[0019] (4) Inject a base fluid that does not contain the CMWF into the rock being stimulated. The purpose of this injection is to break the reservoir rock down and induce a fracture.

[0020] (5) Continue injecting while switching the base fluid to the CMWF until a major portion of the induced fracture surface has been exposed to the CMWF.

[0021] (6) Stop pumping to allow the CMWF to leak-off into the subject rock. This will weaken the rock and enhance the probability of inducing fracture bifurcation. The time for shut-in will vary depending on the leak-off characteristics of the rock matrix, but will normally not be more than a few minutes.

[0022] (7) Reinitiate the fracture with the base fluid and continue pumping as outlined in steps 4, 5, and 6. This "hesitation" fracturing will be done with several cycles. Pressures monitored during the cyclic pumping will give an indication of when to stop the cycling. Reverse flow can also be used in such cycles.

[0023] 8) After the "hesitation" fracturing is complete, a traditional fracturing treatment will be conducted to place proppant, as needed.

[0024] In an embodiment, a method of hydraulic fracturing includes: (a) obtaining a core sample from a reservoir; (b) testing said core sample with a plurality of test surfactants mixed in a hydraulic fracturing fluid and measuring one or more of i) fracture propagation pressure, ii) fracture toughness, or iii) fracture bifurcation index; (c) selecting one or more optimal surfactant(s) for propagating fractures based on the results from step b); and (d) fracturing said reservoir with a fracturing fluid containing said optimal surfactant(s).

[0025] In the various methods of the invention, the testing and selecting steps need not be contemporaneous with the fracturing steps, but are generally performed weeks or months in advance. Further, as test data is collected and assembled for future use, the testing may have occurred even years earlier.

[0026] Furthermore, testing can also include simulated testing, which may become more useful as additional data is generated and modeling systems improve. *See e.g.*, ARMA-08-295 (2008), which describes a geomechanics-based finite-element model with an iterative algorithm that simulates sub-critical quasi-static crack propagation. The model takes into account flow in the porous rock matrix so that its results are applicable to fractured porous media as opposed to crystalline rocks only.

[0027] In preferred methods, the fracturing is by cyclic fracturing with one or more rest periods, or by cyclic fracturing with one or more rest periods and one or more reverse flow periods.

[0028] In another preferred method, the core sample is maintained under reservoir pressure, temperature and humidity conditions during obtaining step a) and testing step b).

[0029] Preferably, the surfactant is use at or above the critical micelle concentration (CMC), e.g., at the $CMC \pm 5\%$.

[0030] In another embodiment, an improved method of hydraulic fracturing includes: injecting a fracturing fluid into a reservoir under sufficient pressure so as to fracture the reservoir; the improvement includes adding a surfactant to the fracturing fluid in an amount sufficient to reduce fracture propagation pressure or reduce fracture toughness or increase fracture bifurcation index.

[0031] In a further embodiment, an improved method of hydraulic fracturing includes: injecting a fracturing fluid into a reservoir under sufficient pressure so as to fracture the reservoir; the improvement includes adding a surfactant to the fracturing fluid in an amount sufficient to cause geomechanical weakening.

[0032] In yet a further embodiment, an improved method of hydraulic fracturing includes: i) injecting a fracturing fluid into a reservoir under sufficient pressure so as to fracture the reservoir, followed by ii) a rest period and iii) an optional reverse flow period and repeating steps i-iii); the improvement comprising adding a surfactant to the fracturing fluid in one or more injecting steps i) in an amount sufficient to cause geomechanical weakening.

[0033] In an embodiment, a method of propagating an existing fracture in a reservoir is provided including: (a) providing a reservoir with one or more existing fractures; (b) propagating said one or more existing fractures by injection an fracturing fluid plus surfactant present at about the CMC; (c) followed by a shut in period plus an optional reverse flow period; and (d) repeating steps b and c until said reservoir is sufficiently fractured.

[0034] Another method provides for improved hydrocarbon drainage including: (a) testing a reservoir with a plurality of test surfactants mixed in a hydraulic fracturing fluid and measuring one or more of i) fracture propagation pressure, ii) fracture toughness, or iii) fracture bifurcation index; (b) selecting an optimal surfactant for propagating fractures based on the results from step b); and (c) fracturing said reservoir with a fracturing fluid containing said optimal surfactant.

[0035] In colloidal and surface chemistry, the “critical micelle concentration” or “CMC” is defined as the concentration of surfactants above which micelles form and all additional surfactants added to the system go to micelles.

[0036] The CMC is an important characteristic of a surfactant. Before reaching the CMC, the surface tension changes strongly with the concentration of the surfactant. After reaching the CMC, the surface tension remains relatively constant or changes with a lower slope. The value of the CMC for a given dispersant in a given medium depends on temperature, pressure, and (sometimes strongly) on the presence and concentration of other surface active substances and electrolytes. Micelles only form above critical micelle temperature. In this disclosure, the CMC is measured under the conditions of use.

[0037] For example, the value of CMC for sodium dodecyl sulfate in water (no other additives or salts) at 25°C, atmospheric pressure, is 8×10^{-3} mol/L. Some exemplary CMC values are provided in Table 2.

Detergent	CMC (%w/v)	CMC (mM)	MW	Type
BRIJ 35	0.11	0.09	1200	non-ionic
NP-40	~0.02	0.05-0.3	~650	non-ionic
Saponin	~0.1		mixture	non-ionic
Triton X-100	~0.02	0.2-0.9	~650	non-ionic
Tween 20	~0.07	~0.06	~1228	non-ionic
SDS	0.23	7-10	288.5	ionic
CHAPS	0.49	6-10	615	zwitterionic

[0038] The use of the word “a” or “an” when used in conjunction with the term “comprising” in the claims or the specification means one or more than one, unless the context dictates otherwise.

[0039] The term “about” means the stated value plus or minus the margin of error of measurement or plus or minus 10% if no method of measurement is indicated.

[0040] The use of the term “or” in the claims is used to mean “and/or” unless explicitly indicated to refer to alternatives only or if the alternatives are mutually exclusive.

[0041] The terms “comprise”, “have”, “include” and “contain” (and their variants) are open-ended linking verbs and allow the addition of other elements when used in a claim.

[0042] The phrase “consisting of” is closed, and excludes all additional elements.

[0043] The phrase “consisting essentially of” excludes additional material elements, but allows the inclusions of non-material elements that do not substantially change the nature of the invention, such as the inclusion of a chelator or any standard additive in the fracturing fluid.

BRIEF DESCRIPTION OF THE DRAWINGS

[0044] The invention, together with further advantages thereof, may best be understood by reference to the following description taken in conjunction with the accompanying drawings in which:

[0045] FIG. 1 shows the general process of hydraulic fracturing.

[0046] FIG. 2 shows a schematic for sample preparation for the Brazilian test.

[0047] FIG. 3 Schematic and picture of Brazilian test set up.

[0048] FIG. 4 CNSCB test and Chevron notch specifications.

DETAILED DESCRIPTION OF THE INVENTION

[0049] Reference will now be made in detail to embodiments of the present invention, one or more examples of which are illustrated in the accompanying drawings. Each example is provided by way of explanation of the invention, not as a limitation of the invention. It will be apparent to those skilled in the art that various modifications and variations can be made in the present invention without departing from the scope or spirit of the invention. For instance, features illustrated or described as part of one embodiment can be used in another embodiment to yield a still further embodiment. Thus, it is intended that the present invention cover such modifications and variations that come within the scope of the appended claims and their equivalents.

[0050] The purpose of this disclosure is to provide methods of reducing the fracture propagation pressure using surfactants at or near the CMC.

[0051] Exemplary surfactants are listed in Table 1. However, the preferred surfactants are non-toxic, having an LD50 of 3,000 mg/kg or higher. Other preferred characteristics include an ability to enhance fracture propagation, but such will vary with each reservoir.

Table 1: Exemplary Surfactants
SDS: sodium dodecyl sulphate
SLS: sodium lauryl sulphate
DTAB: Dodecyl Trimethyl Ammonium Bromide
SPFO: sodium perfluorooctanoate
SOCT: sodium octanoate
Zonyl® 8740-a cationic fluoropolymer that binds and penetrates stone – from DuPont™
Zonyl® FS-200 is a cationic fluorinated surfactant
Zonyl® FS-510 is a Perfluoroalkyl amine oxide surfactants
Zonyl® FSH a nonionic fluorosurfactant

Table 1 cont. Anionic Surfactants Anionic surfactants contain anionic functional groups at their head, such as sulfate, sulfonate, phosphate, and carboxylates. Prominent alkyl sulfates include ammonium lauryl sulfate, sodium lauryl sulfate (SDS, sodium dodecyl sulfate, another name for the compound) and the related alkyl-ether sulfates sodium laureth sulfate, also known as sodium lauryl ether sulfate (SLES), and sodium myreth sulfate. Docusates: dioctyl sodium sulfosuccinate, perfluorooctanesulfonate (PFOS), perfluorobutanesulfonate, linear alkylbenzene sulfonates (LABs). These include alkyl-aryl ether phosphates and the alkyl ether phosphate
Carboxylates These are the most common surfactants and comprise the alkyl carboxylates (soaps), such as sodium stearate. More specialized species include sodium lauroyl sarcosinate and carboxylate-based fluorosurfactants such as perfluorononanoate, perfluorooctanoate (PFOA or PFO).
Cationic head groups pH-dependent primary, secondary, or tertiary amines: Primary amines become positively charged at pH < 10, secondary amines become charged at pH < 4: • Octenidine dihydrochloride; Permanently charged quaternary ammonium cation: • Alkyltrimethylammonium salts: cetyl trimethylammonium bromide (CTAB) a.k.a. hexadecyl trimethyl ammonium bromide, cetyl trimethylammonium chloride (CTAC) • Cetylpyridinium chloride (CPC) • Benzalkonium chloride (BAC) • Benzethonium chloride (BZT) • 5-Bromo-5-nitro-1,3-dioxane • Dimethyldioctadecylammonium chloride • Dioctadecyldimethylammonium bromide (DODAB)
Nonionic surfactant Many long chain alcohols exhibit some surfactant properties. Prominent among these are the fatty alcohols cetyl alcohol, stearyl alcohol, and cetostearyl alcohol (consisting predominantly of cetyl and stearyl alcohols), and oleyl alcohol. • Polyoxyethylene glycol alkyl ethers (Brij): $\text{CH}_3-(\text{CH}_2)_{10-16}-(\text{O}-\text{C}_2\text{H}_4)_1-25-\text{OH}$: • Octaethylene glycol monododecyl ether • Pentaethylene glycol monododecyl ether • Polyoxypropylene glycol alkyl ethers: $\text{CH}_3-(\text{CH}_2)_{10-16}-(\text{O}-\text{C}_3\text{H}_6)_1-25-\text{O}$ • Glucoside alkyl ethers: $\text{CH}_3-(\text{CH}_2)_{10-16}-(\text{O}-\text{Glucoside})_1-3-\text{OH}$: • Decyl glucoside, • Lauryl glucoside • Octyl glucoside • Polyoxyethylene glycol octylphenol ethers: $\text{C}_8\text{H}_{17}-(\text{C}_6\text{H}_4)-(\text{O}-\text{C}_2\text{H}_4)_1-25-\text{OH}$: • Triton X-100 • Polyoxyethylene glycol alkylphenol ethers: $\text{C}_9\text{H}_{19}-(\text{C}_6\text{H}_4)-(\text{O}-\text{C}_2\text{H}_4)_1-25-\text{OH}$: • Nonoxynol-9 • Glycerol alkyl esters: • Glyceryl laurate • Polyoxyethylene glycol sorbitan alkyl esters: Polysorbate • Sorbitan alkyl esters: Spans • Cocamide MEA, cocamide DEA • Dodecyldimethylamine oxide • Block copolymers of polyethylene glycol and polypropylene glycol: Poloxamers Polyethoxylated tallow amine (POEA).

[0052] It will be appreciated that the ideal surfactant will depend in large part on the field conditions, especially such features as type of rock, minor mineral, metal or ion content, pH, salt conditions, porosity, water content, and the like. Until sufficient information is collected about surfactant ability to propagate fractures in various types of rock, it will be necessary to test each rock type against a variety of surfactants and blends thereof. Fracture propagation can initially be tested in benchtop experiments, e.g., with a notched chevron three point bend test, but field tests can be performed instead, and it is envisioned that eventually the needs for such tests will be reduced as sufficient data-points are collected.

[0053] Testing of *in situ* rock or core samples can be by any known or developed method, several of which are provided in the Rock Stress Estimation Special Issue of the International Journal of Rock Mechanics and Mining Sciences, 2003, Volume 40, Issue 7–8.

[0054] Core samples are obtained by drilling with special drills into the reservoir, for example sandstone, shale or rock, with a hollow steel tube called a core drill. A variety of core samplers exist to sample different media under different conditions, and more continue to be invented on a regular basis. In the coring process, the sample is pushed more or less intact into the tube. Removed from the tube in the laboratory, it is inspected and analyzed by different techniques and equipment depending on the type of data desired.

[0055] For example, a rotary coring bit can be used to obtain core samples. Similar to a drillbit, the rotary coring bit consists of solid metal with diamonds or tungsten for cutting at the reservoir rock; but unlike a drillbit, a rotary coring bit has a hollow center.

[0056] Preferably, native state cores (core taken so as to preserve the *in-situ* water saturation of the rock; usually drilled with oil-base mud or crude oil from the same reservoir) are used. As an alternative, measurements can be made *in situ* by known or developed methods, such as described in Haimson, 2003.

[0057] **Fracture Toughness** is a measure of the stress intensity required to initiate crack propagation. The Short Rod Chevron Notch (SR) method is performed on cores less than 55 mm diameter, and the Cracked Chevron Notch Brazilian Disc (CCNBD) method is performed on cores greater than 50 mm diameter. The tests measure the resistance of the rock to being “pulled apart” over a very small cross-sectional area—the tip of a V-notch—and so effectively the intrinsic tensile strength of intact rock substance.

[0058] **Critical Energy Release Rate** or critical crack driving force—The fracture material property which is a measure of the energy required to create new surface area; a function of the fracture toughness, Poisson's ratio, and the modulus of elasticity (i.e. both rock strength and stiffness). G_{Ic} has units N/m

[0059] **Brazilian Tensile Test:** Core samples are sectioned into halves for the Brazilian and CNSCB tests as shown in FIG. 2. 2 cm-diameter cores with longitudinal axis parallel to sample bedding planes are extracted from the 5.0 cm diameter cores as demonstrated in FIG. 2. Finally, two samples are obtained from the 2 cm-diameter core and polished to 1 cm thickness to achieve a length to diameter ratio of 0.5 according to the ASTM specifications (Newman 1990).

[0060] An, e.g., Axial-Torsion MTS 319 loading frame is used to compress the samples diametrically. A schematic of an experiment setup and a Woodford sample under the Brazilian test are shown in FIG. 3. For each depth, a sample is loaded with the loading line parallel to the bedding plane ($\theta_b = 90^\circ$) while the other sample is loaded with the loading line orthogonal to the bedding plane ($\theta_b = 0^\circ$). The loading rate is set at 8.9N/s (2 lb/s) so that the total testing time for each sample is less than 1 minute.

[0061] **Three-point Bending Chevron Notch Semicircular Specimen (CNSCB):** Fracture toughness describes the resistance of the material to the propagation of a preexisting crack. Mode-I fracture can be chosen to simulate wellbore hydraulic fracturing. The remaining sections from the core samples are cut in half and surface ground to achieve a thickness to diameter ratio of approximately 0.5.

[0062] The Chevron notch can produce a stable crack growth and guarantee self-precracking during the test. The notch is formed by two cuts, using e.g., a Dia-Laser saw with thickness of 0.3 mm, outer diameter of 10.2 cm, and inner diameter of 1.3 cm. The initial crack length a_0 , is approximately 6 mm.

[0063] The schematic of the experimental set up is shown in FIG. 4. The notch is cut at 90° with respect to the base of the specimen for mode-I fracture toughness test. The loading span (2S) is fixed at 4.06 cm, which results in a span to diameter ratio (S/D) of 0.8. During the test, the lateral base displacement of the crack is recorded using an MTS clip gage. The gage is mounted to the Plexiglas pads glued on the base of the sample as shown in FIG. 4. Two pairs of 600 kHz compressional piezoelectric crystals are mounted on each side of the sample and in

front of the crack to monitor the acoustic emissions from the fracturing process. A Mistras 2001 AEDSP-32/16 system can be used to record acoustic emission.

[0064] Axial load is applied to the CNSCB samples by Axial-Torsion MTS 319 loading frame. Displacement controlled instead of load control provides a better control of fracture growth. Displacement rate is set constant at 0.0005 mm/sec so that total test time is within 5 min.

[0065] US4152941 describes an older benchtop method of measuring the fracture toughness of rock. A modified ring test is described, wherein fracture toughness, K_{Ic} , comprising the steps of preparing a cylindrical specimen having a longitudinal axis and a cylindrical outer surface, wherein said cylindrical specimen is characterized by the presence of a cylindrical opening therethrough having a common axis with said longitudinal axis, and two diametrically opposed flat surfaces of the same length on said cylindrical outer surface of said cylindrical specimen; applying a compressive displacement at a constant rate on said two diametrically opposed flat surfaces; monitoring the load applied to said specimen resulting from said compressive displacement as a function of displacement; measuring the value of the critical load, F_c , corresponding to the minimum value of the load applied as a function of the displacement at critical crack length; and multiplying the value of the stress intensity factor per unit load for this critical crack length, K_f , times the value of the critical load, F_c , to establish the fracture toughness, K_{Ic} , according to the formula:

$$K_{Ic} = K_f \cdot F_c.$$

[0066] Fracture propagation pressure (FPP) can be measured, e.g., by an *in situ* step rate test, or as described in SPE: 19566-MS. The step rate test is a series of constant-rate injections (“Steps”) increasing from low to high, designed to determine the Formation Parting Pressure (FPP).

CASE 1

[0067] Three lab tests were performed on sandstone cores measuring tensile strength e.g., by the indirect (or “Brazilian”) method. The results showed that surfactants, such as SDS (ionic), CHAPS (Zwitterionic), and Tween-20 (non-ionic) did cause geomechanical weakening. These preliminary tests indicated proof of concept, and suggest that it is worth pursuing additional tests to confirm the value of surfactant use to decrease fracture propagation pressure, and/or fracture length.

[0068] Although various embodiments of the method and apparatus of the present invention have been illustrated in the accompanying Drawings and described in the foregoing Detailed Description, it will be understood that the invention is not limited to the embodiments disclosed, but is capable of numerous rearrangements, modifications and substitutions without departing from the spirit of the invention as set forth herein.

[0069] It should also be noted that in the development of any such actual embodiment, numerous implementation-specific decisions must be made to achieve the developer's specific goals, such as compliance with environmental, technical, and business related constraints, which will vary from one implementation to another. Moreover, it will be appreciated that such a development effort might be complex and time consuming but would nevertheless be a routine undertaking for those of ordinary skill in the art having the benefit of this disclosure. In addition, the compositions and methods used/disclosed herein can also comprise some components other than those cited.

[0070] In the summary and this detailed description, it should be understood that a concentration range listed or described as being useful, suitable, or the like, is intended that any and every concentration within the range, including the end points, is to be considered as having been stated. For example, "a range of from 1 to 10" is to be read as indicating each and every possible number along the continuum between about 1 and about 10. Thus, even if specific data points within the range, or even no data points within the range, are explicitly identified or refer to only a few specific, it is to be understood that inventors appreciate and understand that any and all data points within the range are to be considered to have been specified, and that inventors possessed knowledge of the entire range and all points within the range.

[0071] In closing, it should be noted that the discussion of any reference is not an admission that it is prior art to the present invention, especially any reference that may have a publication date after the priority date of this application. At the same time, each and every claim below is hereby incorporated into this detailed description or specification as a additional embodiments of the present invention.

[0072] Although the systems and processes described herein have been described in detail, it should be understood that various changes, substitutions, and alterations can be made without departing from the spirit and scope of the invention as defined by the following claims. Those skilled in the art may be able to study the preferred embodiments and identify other ways to

practice the invention that are not exactly as described herein. It is the intent of the inventors that variations and equivalents of the invention are within the scope of the claims while the description, abstract and drawings are not to be used to limit the scope of the invention. The invention is specifically intended to be as broad as the claims below and their equivalents.

REFERENCES

[0073] All of the references cited herein are expressly incorporated by reference. The discussion of any reference is not an admission that it is prior art to the present invention, especially any reference that may have a publication data after the priority date of this application. Incorporated references are listed again here for convenience:

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CLAIMS

- 1) A method of hydraulic fracturing of a reservoir to improve drainage, said method comprising:
 - a) obtaining a core sample from a reservoir;
 - b) testing said core sample with a plurality of test surfactants mixed in a hydraulic fracturing fluid and measuring one or more of i) fracture propagation pressure, ii) fracture toughness, or iii) fracture bifurcation index;
 - c) selecting one or more optimal surfactant(s) for propagating fractures based on the results from step b); and
 - d) fracturing said reservoir with a fracturing fluid containing said optimal surfactant(s).
- 2) The method of claim 1, wherein said fracturing is by cyclic fracturing with one or more rest periods.
- 3) The method of claim 1, wherein said fracturing is by cyclic fracturing with one or more rest periods and one or more reverse flow periods.
- 4) The method of claim 1, wherein core sample is maintained under reservoir pressure, temperature and humidity conditions during obtaining step a) and testing step b).
- 5) The method of claim 1, wherein said surfactant is use at or above the critical micelle concentration (CMC).
- 6) The method of claim 1, wherein said surfactant is use at the $CMC \pm 5\%$.
- 7) An improved method of hydraulic fracturing comprising injecting a fracturing fluid into a reservoir under sufficient pressure so as to fracture the reservoir; the improvement comprising adding a surfactant to the fracturing fluid in an amount

sufficient to reduce fracture propagation pressure or reduce fracture toughness or increase fracture bifurcation index.

- 8) An improved method of hydraulic fracturing comprising injecting a fracturing fluid into a reservoir under sufficient pressure so as to fracture the reservoir; the improvement comprising adding a surfactant to the fracturing fluid in an amount sufficient to cause geomechanical weakening.
- 9) An improved method of hydraulic fracturing comprising i) injecting a fracturing fluid into a reservoir under sufficient pressure so as to fracture the reservoir, followed by ii) a rest period and iii) an optional reverse flow period and repeating steps i-iii); the improvement comprising adding a surfactant to the fracturing fluid in one or more injecting steps i) in an amount sufficient to cause geomechanical weakening.
- 10) A method of propagating an existing fracture in a reservoir; said method comprising:
 - a) providing a reservoir with one or more existing fractures,
 - b) propagating said one or more existing fractures by injection an fracturing fluid plus surfactant present at about the CMC;
 - c) followed by a shut in period plus an optional reverse flow period, and
 - d) repeating steps b and c until said reservoir is sufficiently fractured.
- 11) A method of hydraulic fracturing of a reservoir to improve hydrocarbon drainage, said method comprising:
 - a) testing a reservoir with a plurality of test surfactants mixed in a hydraulic fracturing fluid and measuring one or more of i) fracture propagation pressure, ii) fracture toughness, or iii) fracture bifurcation index;
 - b) selecting an optimal surfactant for propagating fractures based on the results from step b); and
 - c) fracturing said reservoir with a fracturing fluid containing said optimal surfactant.

12) The method of claim 11, wherein said surfactant is use at the $CMC \pm 10\%$.

13) The method of claim 11, wherein said surfactant is use at the $CMC \pm 5\%$.

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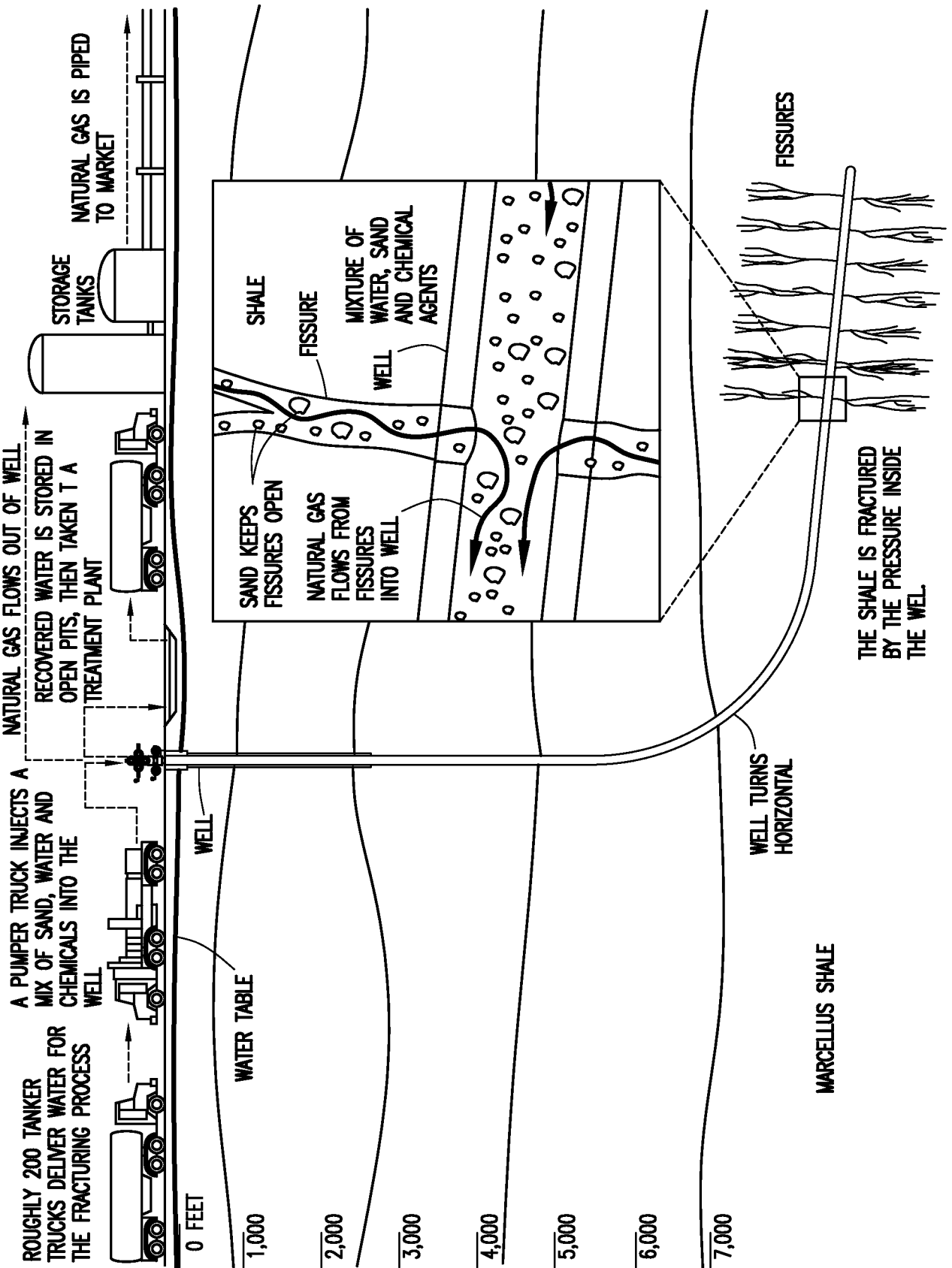


FIG. 1

